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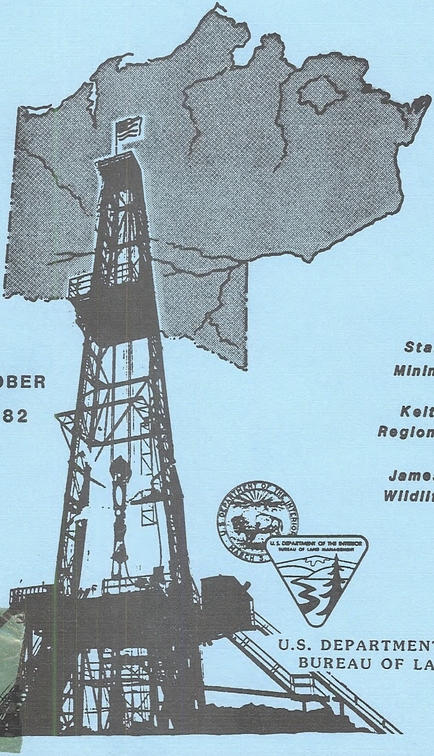
NATIONAL PETROLEUM RESERVE IN ALASKA (NPR-A)

TECHNICAL EXAMINATIONS

TE-I

AN ANALYSIS OF THE TYPE AND LIKELY LEVEL OF NPR-A OIL DEVELOPMENT(S)



OCTOBER
1982

by

Stan Shepard
Mining Engineer

Keith Bennett
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U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

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NPR-A TECHNICAL EXAMINATIONS

TE-1

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I. INTRODUCTION

If discoveries of economically recoverable oil and gas occur, a variety of oil related activities and facilities would come to the wild lands of the National Petroleum Reserve in Alaska. Many of these activities and facilities would pose no direct threat to the environment although the intrinsic value of "primitiveness" might be lost. Other activities or facilities may threaten the viability of highly regarded wildlife or alter fragile landscapes. The purpose of this Technical Examination (TE) is to describe the types and levels of activities and facilities likely to occur so that conclusions may be drawn about how oil development would affect the environment.

The National Petroleum Reserve in Alaska is an area of about 37,000 square miles on the North Slope of Alaska (see back cover). A DEIS to cover a proposed five year leasing program in NPR-A has been prepared for release in October 1982. This TE supports that DEIS.

II. ILLUSTRATIVE NPR-A FIELDS

Simulation techniques were used to identify a likely level of oil and gas development for NPR-A (Department of the Interior 1981). Appendix one discusses how simulation techniques are used to estimate resource potential. This most probable level of oil development includes the likely discovery of three fields, all oil fields. For the purposes of this EIS, gas production was not found to be economically feasible given the high cost of its transportation from the North Slope by pipeline. The smallest oil pool that could be economically produced was estimated at 335 million barrels, while the total production from all fields was estimated at 1.4 billion barrels. Based on model outputs, illustrative fields shown in Table 1 were assigned to the high industry interest areas within NPR-A. These fields have been selected solely for analytical discussion to allow a review of possible effects of discoveries on the varied environments within NPR-A. They are not intended as BLM's speculation or prediction about possible future oil developments on NPR-A. These NPR-A hypothetical fields are to be viewed in the broader context shown in the cumulative development analytical case (page 15).

TABLE 1
LIKELY FIELD SIZES

Illustrative Discussion Fields	Size of Field In Barrels
Kogru River	543,850,000
Smith River	335,300,000
Chipp River	543,850,000
Alaktak River	335,300,000
Peard Bay	543,850,000
Point Belcher	335,300,000
Topagoruk River	543,850,000
Avingak Creek	335,300,000
Utukok River	543,850,000
Liberator	543,850,000
Prince Creek	543,850,000

The geographical names for fields in Table 1 are assigned to facilitate tracking in the impact analysis. It is not probable that any discoveries would occur at these precise locations or be given these names. An analysis of existing fields supports the conclusion that at least two of the fields would be developed near, if not adjacent to, each other. Supporting data are shown in Table 2.

TABLE 2

RELATIONSHIP AMONG FIELDS

Name of Largest (Larger) Field in Complex of Fields	Name(s) of Other Fields of Significant Size	Approximate Dispersion (distance between fields)
Prudhoe Bay	Kuparuk	32
Swanson River	Beaver Creek	8
McArthur River	Trading Bay	3
	Middle Ground Shoal	5
	Redoubt Shoal	9
	Granite Point	11
	Sum of the dispersion -----	68 miles

As can be seen in Table 2, the average dispersion among fields is about 11 miles (18 km) or about two townships. These data support the second assumption, that the Kogru River/Smith River, Chipp River/Alaktak River, Peard Bay/Point Belcher, and Utukok River/Avingak Creek fields would be located next to each other and would be connected by roads. Depending on circumstances, paired fields could share some processing or other facilities.

The modeling process assigned large and small illustrative field development models to areas within NPR-A by use of two criteria. The first criterion, industry interest, is considered the most accurate method of placing these illustrative developments in areas that may have oil potential. It makes no sense to assign even hypothetical fields to areas of no interest to industry. However, to assure that the impacts of development on every sensitive environment would be simulated, a second allocation criterion was developed. This second criterion required that each of NPR-A's six different ecological zones have an illustrative development on the tract with the highest level of interest for that zone (see Figure 1). Once the allocation of illustrative fields was completed, probable layouts for the fields were developed and mapped on 1:250,000 scale maps.

To understand the scale of impacts on the area subject to surface disturbance, an additional review of information on existing Alaska fields was performed. These data on the relationship between wells and production are shown in Tables 3 and 4.

FIGURE ONE
CLASSIFICATION OF NPR-A ENVIRONMENTS

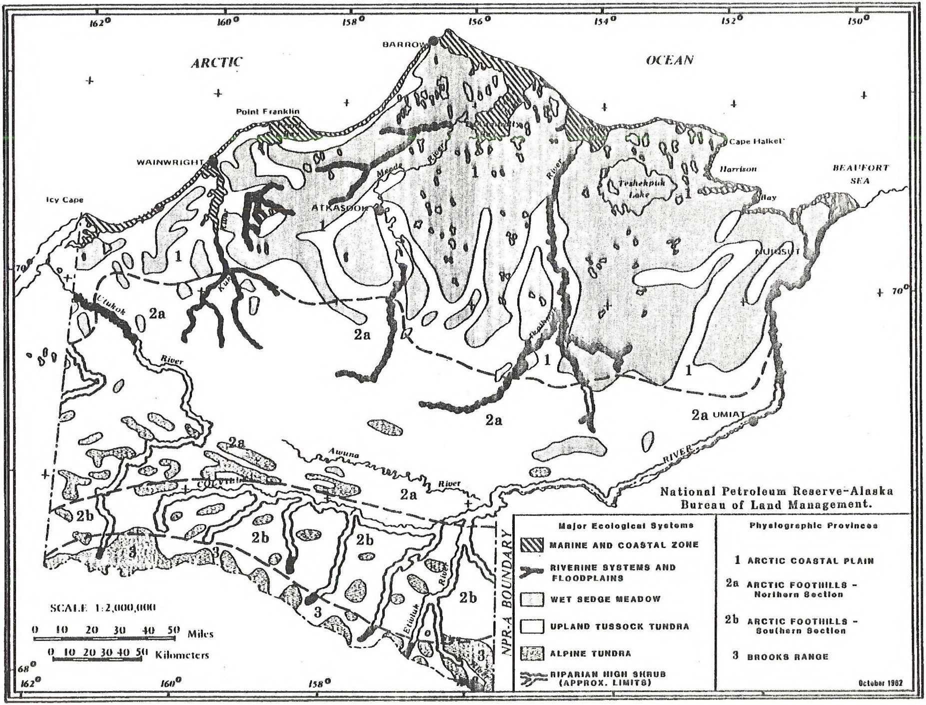


TABLE 3

WELL TO RESERVE RATIOS

Name of Field	Number of Wells At Peak Production	Barrels Produced At Peak Production (millions of barrels per year)	Wells per Million Barrels
Granite Point	28	27	1.04
McArthur River (Hemlock)	37	39	.95
Middle Ground Shoal (E,F,G)	38	24	1.58
Swanson River	55	12	4.58

TABLE 4

PEAK YEAR PRODUCTION AS A PERCENT OF RESERVES

Name of Field	Cumulative Production	Peak Year Production Approximately	Peak Year as a percent of total
Granite Point	85,548,389	27 million	31%
McArthur River	393,381,088	39 million	10%
Middle Ground Shoal	119,025,901	24 million	20%
Swanson River	189,561,312	12 million	6%

Data through 1980. Source: Alaska Oil and Gas Conservation Commission.

All the NPR-A illustrative fields are similar to McArthur River in terms of production level. However, McArthur River was not chosen for the analytical case because it is an offshore field. For analytical purposes, Swanson River, an onshore field, was used to establish the well to production ratio.

Based on Tables 3 and 4, a simplifying assumption about the number of wells in each hypothetical field was made as shown in Table 5.

TABLE 5

ESTIMATED WELL NUMBER FOR NPR-A FIELDS

Recoverable Oil in Barrels	Peak Production (assuming peak year is 6% of total)	Number of Wells (at 4.58 wells per million barrels)
543,850,000	32.6 million barrels	149 wells
335,300,000	20.1 million barrels	92 wells

The amount of land disturbed in each field and the "zone of influence on animal behavior" would then be a function of field design. Therefore, a request was made of the U.S. Geological Survey to analyze current Arctic technologies and develop an illustrative field design. The USGS design indicated a high likehood that directional drilling (deviated, bent, or angle drilling) would be employed in NPR-A. Because of the consolidation of directional drilling, the USGS proto-typical field would have as many as sixteen production wells per pad. Later drilling techniques to enhance field recovery such as waterflood would result in water injection wells being drilled from

the same pads. As a result, large fields could have an estimated ten pads and the small fields would have six pads (149/16 = 9.3; 92/16 = 5.75) assuming an ideal arrangement of the subsurface geology. However, since geology is rarely ideal, modifications were made for the illustrative, geographically named development fields: large fields were allowed from 7 to 12 pads per field and the small fields from 4 to 8 pads.

Assuming a 160-acre spacing per well, each pad of 16 wells would drain a subsurface area of about 2,560 acres (1,036 hectares). The larger fields at ten pads per field would drain a subsurface area of about 25,600 acres (10,360 hectares) and the smaller field at six pads per field would drain about 15,360 acres (6,216 hectares). The surface extent of facilities would vary as a function of the shape of the structure, but the large fields would probably have surface disturbance effects spread over approximately 54-80 square miles (140 to 207 square kilometers). Small fields would cover 36 to 61.2 square miles (93 to 158 square kilometers) at a minimum. Although only a small percentage of surface area within a field would be occupied by facilities, fish and wildlife habitats within or adjacent to the field could be physically altered and/or adversely influenced by oil activities. Animal behavior and diversity may also change in response to development.

The USGS analysis determined that field gathering pipelines would require a 50 foot (15 meter) right-of-way. All roads to pads from the main camp pad/airstrip would parallel pipelines and be 30 feet (9 meters) wide. All-season airstrips, given current Arctic technology, would be about one mile (1.6 kilometers) long and 300 feet (91 meters) wide.

Placing hypothetical developments in various parts of the Reserve provides an opportunity for physical and biological scientists to more precisely identify and predict the likely interactions between oil development and the highly valued features and wildlife of the Reserve.

III. GROUND TRANSPORT

To aid these impact analyses, a forecast was made of the likely level of traffic along an NPR-A haulroad connecting to the Dalton Highway or to Cape Thompson if western discoveries lead to ice breaker tanker movement of oil. On the basis of recent traffic counts by the Alaska Department of Transportation, it appears that there are about three trucks on the Dalton highway each month for every one million barrels produced monthly by Prudhoe (Anderson 1982). By analogy, the coastal illustrative fields of NPR-A would have about 12 to 15 trucks per month traveling to the paired fields. In these fields, the anticipated number of trucks passing a given point (both inbound and outbound would average less than two per day. This analogy would break down for any field unable to receive bulk loads of supplies by barge. However, higher road traffic to inland developments could be controlled by stipulations requiring truck convoys. Presently, any BLM permitted roads within NPR-A will be considered to be private (for the exclusive use of oil and gas operations). BLM intends to require a separate NEPA process for any proposal to make an industry built road in NPR-A a part of the State highway system.

IV. CONFLICT BETWEEN AIRCRAFT AND WILDLIFE

A primary concern during oil development is the effect of aircraft on flightless birds and calving caribou. Strong wildlife reaction to aircraft operating at low altitudes has been noted by a number of researchers. The liklihood and frequency of conflict between wildlife and low flying aircraft can be estimated based on available information from industry on the need for pipeline monitoring flights and weather information.

A. Industry's Views on Pipeline Monitoring Flights

A meeting with operational managers of the major integrated oil firms in Alaska was held at the request of the NPR-A staff. 1/ A summary of the proceedings may be obtained from the BLM Alaska State Office, Lands and Minerals Operations, 701 C Street, Box 13, Anchorage, Alaska 99513.

The consensus from that meeting was that:

1. Supply and shift change flights could operate at high altitudes until they were from about one to three miles from the end of the airstrip;

2. Storage capacity for fuels and other supplies could be increased so that the number of days on which flights into sensitive environments occurred could be substantially reduced (fuel flights could, for example, occur on every tenth day rather than every other day); and,

3. If the roads along the pipeline are private and security of the pipeline is less of a concern, then daily pipeline monitoring flights would not have to be conducted.

B. Weather Information

Before discussing the actual weather data it is important to understand such terms as deck weather days, trade off periods, and conflict days.

DECK WEATHER DAY, as used here, means any day when the ceiling is at or below 1000 feet (305 meters) for fifteen or more consecutive hours. If the pipeline is to be inspected on a day with less than nine hours of ceiling above 1000 feet, it is likely that the fixed wing aircraft or helicopter would have to fly very low (on the deck).

TRADE-OFF PERIODS involve two or more consecutive deck weather days. A single deck weather day predeeded or followed by a day with ceilings above 1,000 feet would not be problematic as the monitoring flight could be rescheduled to avoid low altitude problems.

CONFLICT DAYS are those days during trade-off periods when actual flights may occur at low altitudes. For simplicity we assumed a pipeline monitoring flight would be dispatched every other day.

1/ The Alaska Oil and Gas Association assisted in arranging, hosting and recording the meeting.

Weather data from the National Weather Service Observations at Barrow were analyzed. Weather inland is generally better than coastal weather (personal communication, Gary Landee, OAS Pilot, Barrow, Alaska). Using Barrow data maximizes the apparent conflicts. Under our assumption of monitoring flights every other day, bad weather on two consecutive days would mean that a low flying aircraft would be dispatched. The conflict days are (C) or (c) entries depending on whether or not the trade-off period is in a time very sensitive for both birds and caribou (C) or very sensitive primarily for birds (c). (See Matrix One).

Deck weather days when flights would not have to be dispatched (under the assumption of monitoring flights every other day) are shown by (d) entries. A (d) standing alone would not represent a trade off period as the monitoring flight could be dispatched on the day preceeding or following. Thus a Cd or dc, representing at least two consecutive deck weather days, is the minimum sequence fitting our concept of a trade off period.

The interpretation of the entries in Matrix One are:

1. While there is great variation on a day to day basis in the occurrence of deck days, there is far less year to year variation in the total number of deck days or the number and average length of trade off periods. For example, there were six trade off periods averaging 4.33 days in length in 1981, five averaging 6.2 days in length in 1980, eight averaging 2.88 days in length in 1979, six averaging 5.0 days in length in 1978 and seven of 3.43 days in length in 1978. The average number of trade off periods is six (the mode is six, the median is six, the mean is 6.1). The thirty-two trade off periods averaged 4.2 days in length;

2. In the 47 days of extremely sensitive period caribou calving from May 15 through June 30 there were seven trade off periods over the five years (an average of 1.4 a year). There are thirty-four (C) entries in the matrix identifying those days in the five years when flights would have had to have been low altitude, an average of 6.8 events adversely influencing caribou each year; and,

3. The 104 day period of high sensitivity of birds to disturbances (from May 20 through August 31) overlapped all 32 trade off periods in the five years. Thus for birds there would be on an average of 6.1 trade off periods each year. There are, in addition to the thirty-four (C) entries in the matrix, thirty-seven (c) entries for a total number of seventy-one low altitude flight/bird conflict days in the five years. This indicates an average of 14.2 events per year adversely influencing waterbirds.

The following interpretation of the information in the matrix supports these conclusions:

1. Flights on the deck (below 1000 feet) which affect wildlife during sensitive periods are almost certain if a pipeline is built above Teshekpuk Lake or into the Utukok calving area; and

2. The amount of time that wildlife would be subject to disturbance would represent a minor share of the total period of sensitivity.

DECK WEATHER FREQUENCY

MATRIX ONE

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
May																														
1981																										C	d	C	d	C
80																			C	d	C	d	C	d	C	d		d		
79	The Sensitive Season Commences in Mid May																											d		
78																		C	d	C	d	C	d	C	d	C	d			d
77																	C	d							C	d		d		
June																														
1981						C	d			d							d		d							C	d	C	d	C
80																														
79						d				C	d	C	d	C				C	d	C		C	d							
78	C	d	C							d		C	d	C		d					d			d						
77	d				d		C	d	C					d					C	d	C		C	d	C	d				
July																														
1981				d	c	d	c	d			d						d		d											
80				c	d	c	d	c	d	c	d	c	d	c	d				c	d			d		d		d			d
79							d		d												d						d			
78			d										c	d		d				d		d								
77				c	d																d						d			
August																														
1981	d				d				c	d	c	d	c			c	d	c	d				d							
80			d			c	d	c	d	c			d								d			c	d	c	d			
79		d		c	d		c	d							c	d	c	d	c		c	d					c	d		
78				c	d			c	d	c	d	c	d	c	d	c						d			d					
77						c	d	c	d	c	d	c	d																	

Legend
c=deck weather day when a flight occurs during a time when only birds are vulnerable
C=deck weather day when a flight occurs during a time when both bird and caribou are vulnerable
d=deck weather when no flight is dispatched

For example, low flights over caribou would occur during six percent of the sensitive period (nine hours of flight time per monitoring flight, times seven adverse events per year, divided by 24 hours per day, times forty-seven days during the sensitive period). Birds would experience low flight disturbance during about five percent of the sensitive period .

V. EMPLOYMENT IMPLICATIONS (PROJECT EMPLOYMENT)

To aid in the impact analysis, an estimate of the labor needs for field development was prepared, including pipeline construction and operation.

NPR-A pipelines exiting the Reserve are estimated to vary from 14 to 22 inches (35 to 55 centimeters) in diameter. A peak construction workforce of 1,000 persons for this diameter pipeline is estimated for the pipeline plus 60 construction workers to assemble pump stations.

While the pipeline is being constructed, a number of other development activities could take place as shown in Table 6 (not necessarily in order of construction).

TABLE 6

NPR-A WORKFORCE REQUIREMENTS

	Peak Work Force	
Activity	Large Field	Small Field
Build Additional Well Pads	60	30
Drill Development Wells	125	65
Assemble Central Production Facility (CPF)	750	750
Build Base Camp and Assemble Camp Buildlings	*	*
Build Intrafield Roads and Pipelines	120	90
Build Pipeline/Road Maintenance Camps	200	200

* Extension of the same personnel that worked on the CPF.

Total peak employment for all concurrent activities associated with the construction phase of development of one field would range between 2,195 and 2,315 workers.

Based on the Alaska State Office Onshore Workforce Model, (see endnotes), total project employment during production would average 720 workers for each large field and 485 workers for the small field (1,925 for all fields). A producing field would require 245 workers on site at any given time for large fields and 150 workers for small fields. There would be 90 overhead employees in Anchorage for each field. Total oil company employment would, therefore, be 580 employees (490 "oil field workers"; 90 overhead personnel in Anchorage) for each large field and 390 employees for the small field (300 "oil field" workers; 90 overhead in Anchorage). This assumes that each "oil field" worker is on for two weeks and off two weeks and that there are, therefore, two workers for each job. In Alaska oil field service employment (OFS) averages about .24 OFS jobs for each job with the producing company (State of Alaska 1982). There would be about 140 OFS jobs created for each large field (.24 times 580) and about 95 OFS jobs associated with each small field (.24

times 390). Thus, with regard to airline service for shift change, probably at least three flights every week would be needed for changeout at each field (this assumes that the crews are staggered. That is, when the field goes into production crew A (day crew) works a week then is off for two, crew B (night) works two then is off two, crew C (day) comes on after crew A and overlaps one week of crew B and crew D (night) comes on after crew B overlapping crew C for a week then overlapping crew A when A returns.) Flights to provide fuel, to resupply perishable food and to monitor the pipeline may happen as frequently as one flight every other day.

VI. EIS ANALYTICAL CASES (CONCURRENT NPR-A DEVELOPMENTS)

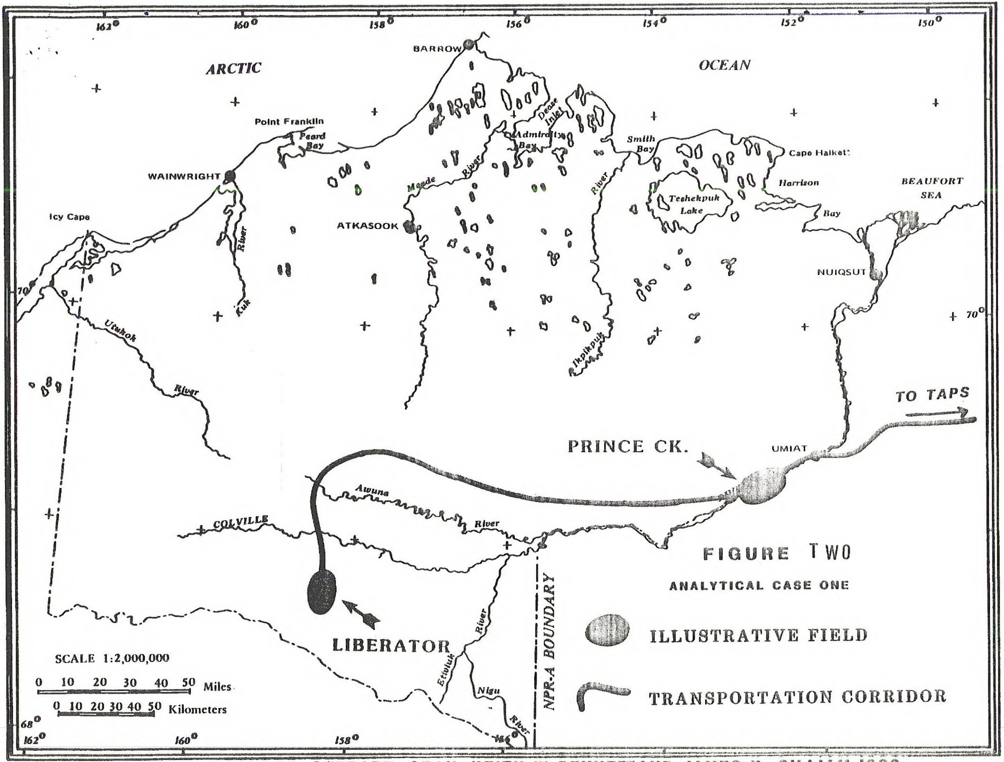
To facilitate discussion of the likely level and types of impact which could result from NPR-A development, several combinations of fields, called "cases" were developed. The combinations of fields are listed in Table 7 and shown in Figures 2, 3, 4 and 5. It is important to note that these cases would have production which varies from the illustrative forecast of 1.4 billion barrels of economically recoverable crude oil for all of NPR-A. This variation was purposely introduced to allow flexibility in the analysis and to point out the fact that forecasting is an imprecise science.

TABLE 7

Analytical Cases By Case Number

*	Prototypical Fields (or Field Complexes)	Estimated/Hypothetical Date Production Commences
Case One	Liberator	1990
	Prince Creek	1990
Case Two	Chipp River/Alaktak Complex	
	Chipp River	1997
	Alaktak	1998
	Smith River/Kogru Complex	
	Smith River	2000
	Kogru	2002
Case Three	Liberator	1990
	Avingak/Utukok Complex	
	Utukok River	2003
	Avingak Creek	2003
Case Four	Liberator	1990
	Peard Bay/Point Belcher Complex	
	Peard Bay	2002
	Point Belcher	2002
	Avingak/Utukok Complex	
	Utukok River	2003
	Avingak Creek	2003

* A burst of high intensity activity involving development drilling and road, pipeline and facility construction would occur in each field for two to three years before production commences.



SOURCE: SHEPARD, STAN; KEITH W BENNETT AND JAMES K. GILLIAM, 1982

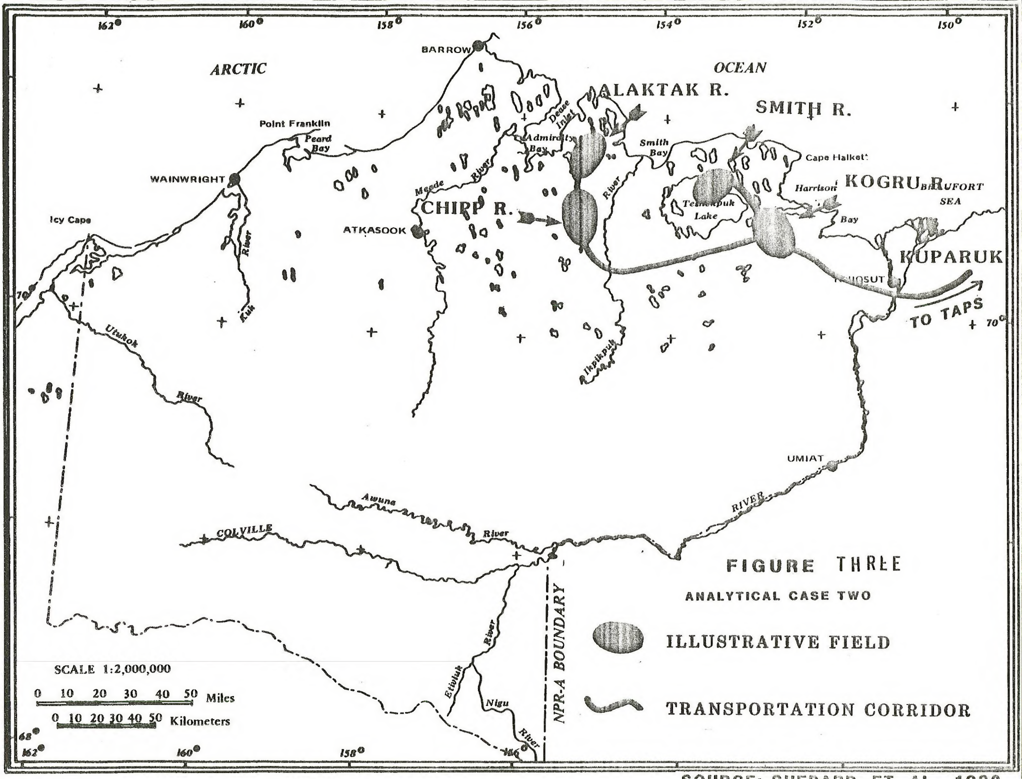


FIGURE THREE

ANALYTICAL CASE TWO

SOURCE: SHEPARD, ET. AL., 1982

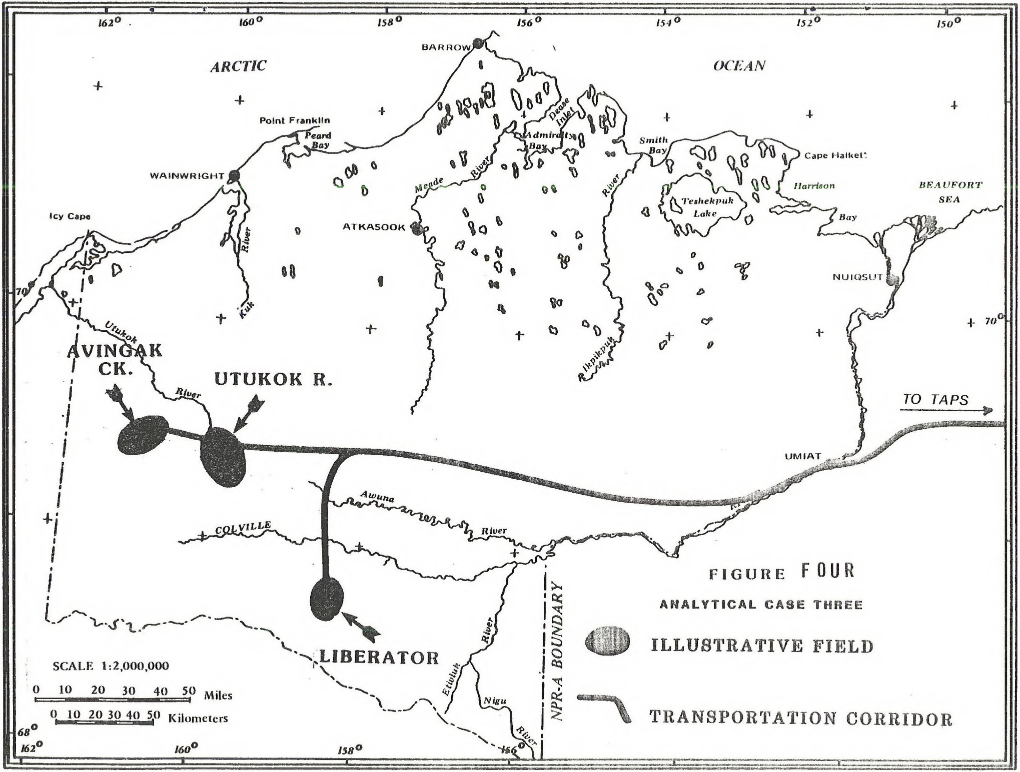


FIGURE FOUR

ANALYTICAL CASE THREE

SOURCE: SHEPARD, ET. AL., 1982

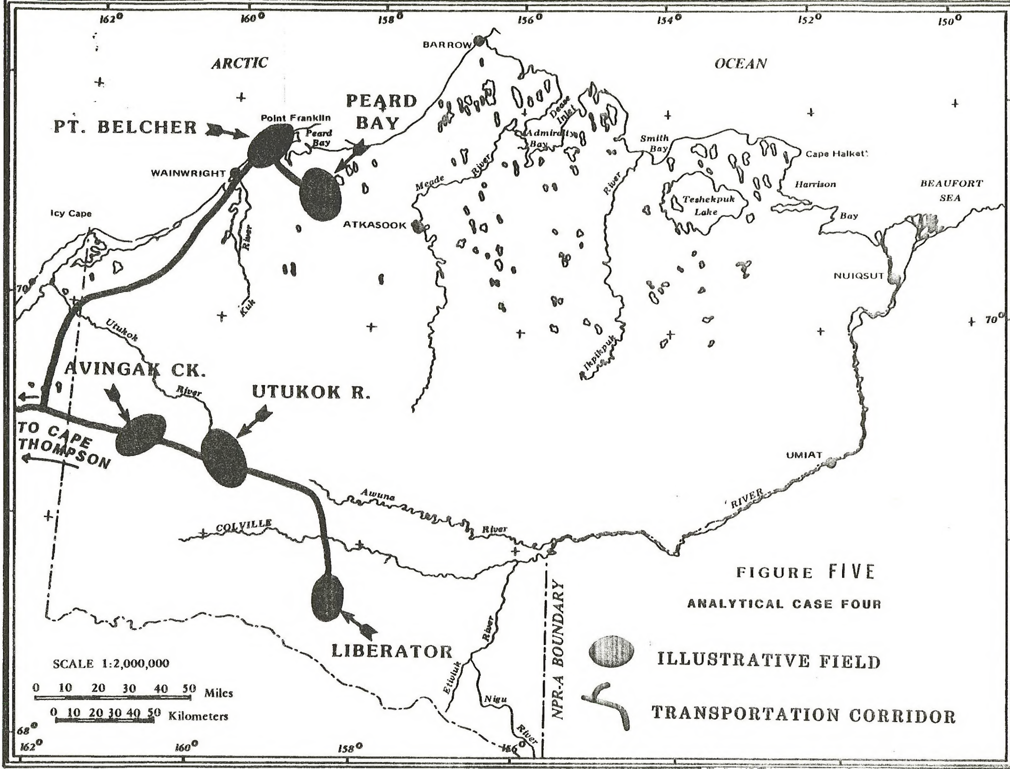


FIGURE FIVE

ANALYTICAL CASE FOUR

SOURCE: SHEPARD, ET. AL., 1982

VII. CUMULATIVE DEVELOPMENT NORTH OF THE BROOKS RANGE

There are two major divisions into which the uncertain future of North Slope oil development can be placed. One future has no additional discoveries, the other has additional discoveries. TE-1 assumes that the second outcome is more likely; that is, that additional discoveries will be made.

As of the drafting of this TE there had been, to the knowledge of the TE authors, no specific forecasts of where discoveries would occur and what size the resulting fields might be. This reluctance to make specific forcasts is understandable given the paucity of information on the lightly explored North Slope. However this information void makes it difficult for the reader to gain a feeling for the possible cumulative impacts of concurrent development. The information set out below was developed for discussion and analysis purposes to illustrate the possible effects of concurrent development. The reader should view our forecast cautiously. It is almost certain that when actual fields are discovered they would be of different sizes then, and in different locations from, those which appear in our illustrative cumulative impact case.

Two conclusions seem warranted concerning Arctic wide development. They are:

1. It is likely that any basin with a field greater than one billion barrels would have additional large fields; and

2. The distribution of oil in these additional large fields could be used to estimate, by analogy, the level of future new discoveries on the North Slope.

Data on how fields are distributed in various basins of the United States are shown in Table 8 (International Petroleum Encyclopedia 1981). The percentage figures which are asterisked in Table 8 were used as the basis for the cumulative analytical case. The asterisked percentages can be used to provide an illustrative combination of the North Slope fields. These illustrative fields are shown in Table 9.

Table 10 rank orders the North Slope fields, including the illustrative NPR-A fields, by size of field. Taken together, the new fields in Table 10 have total undiscovered recoverable reserves of 15,333,000,000 barrels (the 16,408,000,000 total less Kuparuk's 1,075,000,000 barrels). This estmate of 15,333,000,000 barrels is almost precisely equal to the 15,400,000,000 barrels of undiscovered recoverable reserves estimated by the U.S. Geological Survey (DOI 1981) as the most likely case for the entire area North of the Brooks Range. Table 11 shows the USGS estimates by area.

T A B L E 8

U.S. Oil Producing Areas

Existing Fields	San Joaquin (CA)		Los Angeles (CA)		District Eight (TX)		District Eight A (TX)		Onshore South (LA)		Lousianna Offshore		Wyoming	
	Barrels (Thousands)	(%)	Barrels (Thousands)	(%)	Barrels (Thousands)	(%)	Barrels (Thousands)	(%)	Barrels (Thousands)	(%)	Barrels (Thousands)	(%)	Barrels (Thousands)	(%)
Largest	1,864,312	(100)	2,400,787	(100)	1,950,000	(100)	1,629,730	(100)	680,000	(100)	619,516	(100)	650,650	(100)
Second Largest	1,632,008	(87.5)	1,078,929	(44.9)	735,000	(37.8)*	1,350,000	(82.8)	300,678	(44.2)	543,208	(87.8)	478,317	(73.5)
Third Largest	1,416,560	(76.0)	933,635	(38.9)	510,000	(26.2)*	1,000,000	(61.4)	265,000	(39.0)*	384,427	(62.1)	451,101	(69.3)
Fourth Largest	723,352	(38.8)	615,253	(25.6)	485,000	(24.9)*	559,951	(34.4)	260,000	(38.2)	263,099	(42.5)	384,479	(60.0)
Fifth Largest	706,147	(37.9)	305,562	(16.1)*	450,000	(23.1)	471,171	(28.9)	255,000	(37.5)	193,254	(31.2)	357,792	(55.0)
Sixth Largest	653,861	(35.1)	350,149	(14.6)*	406,927	(20.9)	425,000	(26.1)	250,000	(36.8)	193,179	(31.2)	350,679	(53.9)
Seventh Largest	471,381	(25.3)	272,817	(11.4)*	365,000	(18.7)	310,000	(19.0)	244,440	(36.0)	147,760	(23.9)	325,000	(50.0)
Eighth Largest	457,342	(24.5)	251,037	(10.5)*	335,000	(17.4)	260,000	(16.0)	230,000	(33.8)	131,374	(21.2)	280,104	(43.1)
Ninth Largest	269,688	(14.5)	214,220	(8.9)*	319,899	(16.4)	256,360	(15.7)	25,000	(33.0)	107,308	(17.3)	274,980	(42.3)
Tenth Largest	241,589	(13.0)	203,379	(8.5)*	264,730	(13.6)	200,000	(12.3)	190,000	(27.9)	100,000	(16.2)	260,436	(40.0)
T O T A L Fields Two Through	6,571,928	(352.5)	4,304,981	(179.3)	3,875,556	(198.8)	4,832,482	(296.5)	2,220,118	(326.5)	2,063,609	(333.1)	3,162,988	(486.1)

(note to reader: the data in this table are in thousands of barrels. Thus, the largest field in the San Joaquin basin should be read as one billion, 864 million 312 thousand barrels).

* The asterisks are associated with the worst relationship cases.

TABLE 9

Arctic Fields Identified

Field Name	Barrels	Percent of Largest	Allocated to
*Prudhoe Bay	9,429,938,000	100.0	Prudhoe Bay
Second Largest	3,565,000,000	37.8	Beaufort Sea
Third Largest	2,471,000,000	26.2	Arctic National Wildlife Refuge
Fourth Largest	2,348,000,000	24.9	Beaufort Sea
Fifth Largest	1,518,000,000	16.1	Chukchi Sea
Sixth Largest	1,377,000,000	14.6	Beaufort Sea
*Seventh Largest	1,075,000,000	11.4	Kuparuk River
Eighth Largest	990,000,000	10.5	Chukchi Sea
Ninth Largest	839,000,000	8.9	Beaufort Sea
Tenth Largest	802,000,000	8.5	State of Alaska Uplands East of NPR-A
Second through tenth	14,985,000,000	158.9	

* Asterisks indicate existing fields. The full extent of the Kuparuk River field has not yet been defined and estimates of total recoverable reserves in that field are (A) tentative and (B) creeping upward. The 1,075,000,000 barrel estimate shown in our table does not correspond to any official estimate of total Kuparuk reserves.

A. Level of Esploration Activity

There are eleven undiscovered fields shown in Table 10. In recent years (Exxon 1981) industry has been drilling about 5.5 new field wildcats for each discovery well. This implies that about 55-65 exploratory wells would be drilled in all areas of the North Slope Borough in the search for the eleven illustrative undiscovered fields. About fourteen to eighteen of these exploratory wells would be within NPR-A.

T A B L E 10

Distribution of Major North Slope Fields Other Than Prudhoe

Field Location		Size in Barrels
Beaufort Sea		3,565,000,000
Arctic National Wildlife Refuge		2,471,000,000
Beaufort Sea		2,348,000,000
Chukchi Sea		1,518,000,000
Beaufort Sea		1,377,000,000
Kuparuk River		1,075,000,000
Chukchi Sea		990,000,000
Beaufort Sea		839,000,000
Alaska Uplands East of NPR-A		802,000,000
NPR-A		543,850,000
NPR-A		543,850,000
NPR-A		335,300,000
	Total*	16,408,000,000

* Several discoveries have been made east and west of Prudhoe Bay which may or may not represent economically recoverable fields. These fields are not shown in the table above.

T A B L E 11

USGS Mean Recoverable Resource Estimates

Arctic Coastal Plain		4,400,000,000
Northern Foothills		1,400,000,000
Southern Foothills/Brooks Range		201,000,000
Beaufort Near Shore		7,000,000,000
Beaufort Deeper Waters		800,000,000
Chukchi Near Shore		1,400,000,000
Chukchi Deeper Water		200,000,000
	Totals	15,400,000,000

B. Overview of Cumulative Impacts

Five of these eleven undiscovered illustrative fields would be onshore and six would be offshore. Cumulative impacts of NPR-A and offshore fields would fall primarily on birds and mammals in the terrestrial and marine envrionments. The offshore fields would affect polar bear, seals, beluga whales, walrus and other marine mammals which live on or under Arctic ice. The two onshore fields outside of NPR-A (fields three and ten in Table 9) would have impacts on terrestrial mammals, fisheries and waterbirds to cumulate with the NPR-A fields. A biological opinion on the nature and extent of these cumulative impacts will be provided on a topic-by-topic basis in the NPR-A oil and gas leasing DEIS.

VIII. ESTIMATED CAPITAL REQUIREMENTS FOR NPR-A FIELD DEVELOPMENT

The Minerals Management Service (MMS) provided proprietary information to the BLM for use in determining the acceptability of high bids at the first several NPR-A sales. While these data cannot be directly disclosed, they provide a basis for estimating the capital requirements of the illustrative NPR-A fields.

These MMS provided data have been disguised to avoid disclosure of proprietary estimates of key economic characteristics of the tracts offered at these several sales. Table 12 shows the disguised data.

TABLE 12
Field Costs By Field Size and Location

Frontier Area	Field Size (well number)	Development Cost (1982 dollars)
Overthrust	32	$853,757,440
	32	870,011,136
	37	271,774,976
	32	803,322,880
	36	374,266,240
	30	777,466,368
	32	870,011,136
	30	667,255,040
	37	271,500,554
	32	870,011,136
	36	428,311,296
	36	432,503,808
	37	271,500,544
	32	865,435,136
South Simpson	96	967,942,400
	96	840,023,296
	96	825,539,840
	48	262,743,264
	48	262,983,480

These data indicate an estimated cost per average well in the Overthrust Frontier Area of $18,316,619.30 (1982 dollars). An average South Simpson Frontier Area well would cost $8,227,167.92 (1982 dollars).

Using these average well costs and using a set of illustrative fields in these frontier areas, estimated capital costs were derived. These capital costs can form the basis for a property tax revenue stream estimate. Such a tax stream estimate may be helpful to the North Slope Borough if discoveries are made in NPR-A. The NSB could use the estimated tax stream as a basis for revenue anticipation bonds. These bonds could be used by the Borough to provide new or increased community services. These services may be needed by those Inupiat who remain on the North Slope to take NPR-A jobs. The Borough may also use the revenue anticipation bond proceeds to finanace the construction of oil field service facilities such as waste incineration plants. By operating those service facilities the Borough could deversify its revenue sources and provide additional jobs for Inupiat.

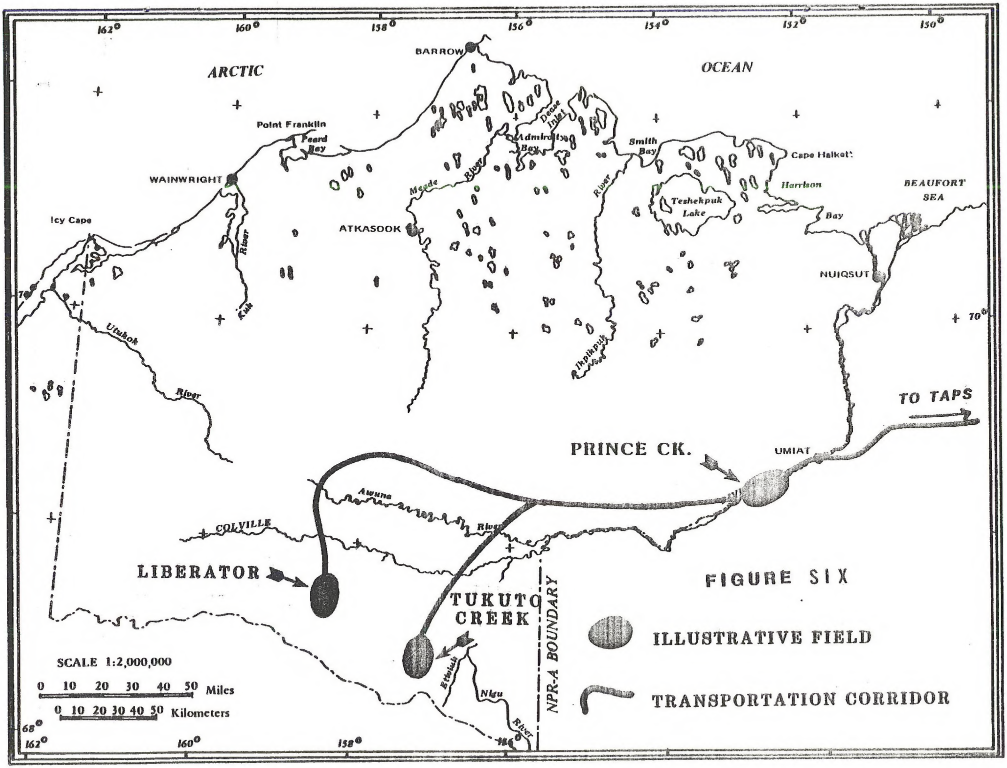
Table 13, which estimates the capital requirements of the illustrative fields, would form the basis for such a property tax revenue stream forecast. A property tax revenue stream forecast is being prepared and will be forwarded to the Honorable Eugene Brower, Mayor, North Slope Borough for review. Individuals and organizations interested in this analysis may request it from the Bureau of Land Management, Lands and Minerals Operations, 701 C Street, Box 13, Anchorage, AK 99513.

TABLE 13

Capital Requirements of Illustrative NPR-A Fields

(Figure 6 shows this combination of fields)

Frontier Area	Field Name	Well Number	Estimated Capital Cost (1982 dollars)
South Simpson	Prince Creek	149	$1,225,848,020
Overthrust	Liberator	149	2,729,176,276
	Tukuto Creek	92	1,685,128,976



162°
160°
158°
156°
154°
152°
150°
BARROW
ARCTIC
OCEAN
Point Franklin
Peard Bay
Dease Inlet
Admiralty Bay
Smith Bay
Cape Halkett
WAINWRIGHT
Meade
River
Harrison
Bay
BEAUFORT SEA
Teshekpuk Lake
Icy Cape
ATKASOOK
River
Kuk
NUIQSUT
70°
Utukok
River
Ikpikpuk
TO TAPS
PRINCE CK.
UMIAT
Awuna
River
COLVILLE
LIBERATOR
TUKUTO CREEK
NPR-A BOUNDARY
FIGURE SIX
ILLUSTRATIVE FIELD
TRANSPORTATION CORRIDOR
SCALE 1:2,000,000
0 10 20 30 40 50 Miles
0 10 20 30 40 50 Kilometers
Etivluk
Nigu
River
68°
162°
160°
158°
156°

END NOTES
ONSHORE WORKFORCE MODEL *

PHASE	INDUSTRY	TASK	UNIT OF ANALYSIS	DURATION OF EMPLOYMENT	CREW SIZE OR MONTHLY WORK FORCE	SHIFTS PER DAY
EXPLORATION	OIL AND GAS	EXPLORATION WELLS	WELLFOOT	ONE DAY PER 90 FEET DRILLED	75-100	2
	CONSTRUCTION	AIRSTRIPS	STRIP	120 DAYS	6 WORKERS	1
		WELL PADS/CAMPS	WELL	20 DAYS/PAD	20 WORKERS	1
		ICEROADS	WELL	VARIABLE	40 WORKERS PER DAY PER MILE	1
	TRANSPORTATION	SHUTTLE RIGS	WELL (50 SHUTTLES PER RIG)	ONE WEEK FOR EVERY TEN MILES	75	1
DEVELOPMENT	OIL AND GAS	DEVELOPMENT WELLS	WELL	30 DAYS/WELL	50-75	1
	CONSTRUCTION	AIRSTRIPS	FIELD	30 DAYS/FIELD	50	1
		CENTRAL PROCESSING FACILITY (CPF)	FIELD	NINE MONTHS PER CPF	50 (LOW) TO 750 (PEAK)	1
		WELL PADS	WELL OR GROUP OF	20 DAYS PER PAD	30	1
		CAMP AND CAMP BUILDING	FIELD	1½ MONTHS	50 (LOW) TO 250 (PEAK)	1

* Prepared by the NPR-A Regional Economist in consultation with the Alaska Oil and Gas Association and the U.S. Geological Survey.

END NOTES
ONSHORE MANPOWER MODEL

PHASE	INDUSTRY	TASK	UNIT OF ANALYSIS	DURATION OF EMPLOYMENT	CREW SIZE OR MONTHLY WORK FORCE	SHIFTS PER DAY
DEVELOPMENT (continued)	CONSTRUCTION (continued)	PIPELINE ONSHORE, GATHERING	MILE	TWO YEARS PER MILE	5 WORKERS	1
		PIPELINE ONSHORE, TRUNK	MILE	TWO YEARS	5 WORKERS PER MILE	1
		PIPELINE ONSHORE, PUMP STATIONS	SITES	NINE MONTHS PER STATION	4 (LOW) TO 60 (PEAK) WORKERS PER STATION	
		PIPELINE ONSHORE, MAINTENANCE CAMPS	CAMPS	THREE MONTHS PER CAMP	50 WORKERS PER CAMP	
PRODUCTION	ALL SECTORS	FIELD TOTALS	FIELD	LIFE OF FIELD (LOF)	90 OVERHEAD IN ANCHORAGE (45 workers in the Field (22.5 jobs) for each 100 mm barrels of production.)	1
	OIL AND GAS	OPERATIONS AND MAINTENANCE	FIELD	(LOF)	50% OF FIELD PERSONNEL	2
		WORKOVER AND WELL STIMULATION	FIELD	(LOF)	25% OF FIELD PERSONNEL	2
	CONSTRUCTION	ROAD REPAIR	MILE	(LOF)	5% OF FIELD PERSONNEL	2

END NOTES
ONSHORE MANPOWER MODEL

PHASE	INDUSTRY	TASK	UNIT OF ANALYSIS	DURATION OF EMPLOYMENT	CREW SIZE OR MONTHLY WORK FORCE	SHIFTS PER DAY
PRODUCTION (continued)	CONSTRUCTION (continued)	FACILITY REPAIR	NUMBER OR SQUARE FOOTAGE OF BUILDINGS	(LOF) PERSONNEL	20% OF FIELD	2
	TRANSPORTATION	SHUTTLE WORKERS				
		SHUTTLE SUPPLIES	FIELD	(LOF)	6 -10	1
		PIPELINE OPERATIONS	PUMP STATION	(LOF)	5	1

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A P P E N D I X O N E

1. Introduction

This Technical Examination stated that simulation techniques were used to estimate NPR-A oil and gas resources. Simulation techniques rely partially on computers to perform high speed mathematical calculations. However, the relationships within the computer model are all based on professional judgment. These professional judgments fall into two groups; geologic interpretations and economic considerations.

2. Geology

Geologists perform a complex task in assessing the oil and gas potential of any area. Geologists must look for evidence that oil or gas (hydrocarbons) could have been "created" by historic geologic forces, that these hydrocarbons could have moved (migrated) out of areas when they were created and that the oil and gas could have then accumulated in any one of a number of traps. These geologic characteristics are discussed below.

The primary information used in building a model of the geology of a frontier area is the occurrence of "plays". As a result of a preliminary assessment by the USGS, NPR-A has been divided into 17 petroleum plays (stratigraphic units of relatively homogeneous geology), which are the primary units of geologic analysis used in this appraisal. The identification of "plays" is based on four regional geologic characteristics. These "play" characteristics are; the existence of a petroleum source, favorable timing, potential migration paths and the existence of reservoir rock. Each of these characteristics has its own probability of occurrence. The joint probability that all the regional geological characteristics necessary for the accumulation of petroleum in the play area are simultaneously favorable is derived by multiplying together the probabilities for each characteristic. Each play characteristic is a necessary but not sufficient condition for the existence of oil or gas deposits in the play.

Second order geologic judgments deal with prospects within plays. Each prospect is evaluated for trapping mechanism, effective porosity, and petroleum accumulation.

Third order judgments involve reservoir volume parameters. The reservoir characteristics are: area of closure, reservoir thickness, effective porosity, trap fill, water saturation, and reservoir depth. The reservoir volume parameters jointly determine the volume of space which recoverable oil or gas may fill.

These three basic sets of judgments were made for each of the 17 NPR-A plays. For each play, the computer reviewed the potentially drillable prospects in the probability distribution and determined the number of prospects that would be simulated. The marginal play probability was then sampled to determine whether the play would be simulated as unproductive or potentially productive during the pass. For each prospect in a productive play, the conditional deposit probability was sampled to determine whether that prospect would be simulated as an actual deposit or as dry. The petroleum mix probability was sampled for each simulated deposit to determine whether it contained oil or gas. All prospects in an unproductive play were automatically simulated as dry.

Each of the reservoir volume distributions is sampled for each of the prospects (both dry prospects and deposits) to simulate their volume and reservoir characteristics.

Finally, the program allocated the prospects from each play to the appropriate overlying surface area or areas. The primary output of the model was a prospect list for each activity area along with an estimate of oil and gas reserves based on the computer provided estimates of the number of wet prospects out of the universe of all prospects in a play.

3. Economic Considerations

While the prospect list generated by the computer has put limits on the uncertainty associated with exploration in a frontier area, there are many pressing questions unanswered. For example, the oil industry may see enormous costs associated with NPR-A exploration and field development or great difficulty in securing transportation for any hydrocarbon discoveries. These costs and transportation constraints are inputs into economic models. The economic analysis examines, among other isssues, how much an oil firm can spend to aquire a prospect with a given reservoir potential and how much the firm can afford to invest in exploration. A firm analyzing whether it can "afford" to acquire and explore a prospect, views the capital it will lay out for these front end costs as residual funds in an economic sense. By residual funds an economist means that the economic model will, given the likely production from the prospect and based on future estimates of prices, calculate (A) how much it will cost to develop and operate the field (including interest payments and production based taxes), (B) how much the company would receive; (C) determine whether the remaining balance (difference between costs and revenues) is enough to pay a fair return to the firm's investors; and, (D) allocate whatever is left to acquiring and exploring the lease. These calculations may lead the oil industry to conclude that none of the prospects in a play are worth exploring.

4. Summary of the Simulations

By now the model has looked at the universe of possible prospects and, in the geology submodel, estimated the number with hydrocarbons and the number which are likely to be dry. For the set of prospects likely to contain hydrocarbons the geology submodel has estimated likely reservoir volumes for each prospect. Using these reservoir volumes and based on cost and future price considerations the economic submodel has identified a subset of prospects which appear to be economically recoverable. The model run for BLM by the Office of Minerals Policy and Resource Analysis, concluded that only 2.15 prospects in NPR-A would be found to be economically recoverable. Total oil produced in the most likely case was estimated at 1,463,000,000 barrels.

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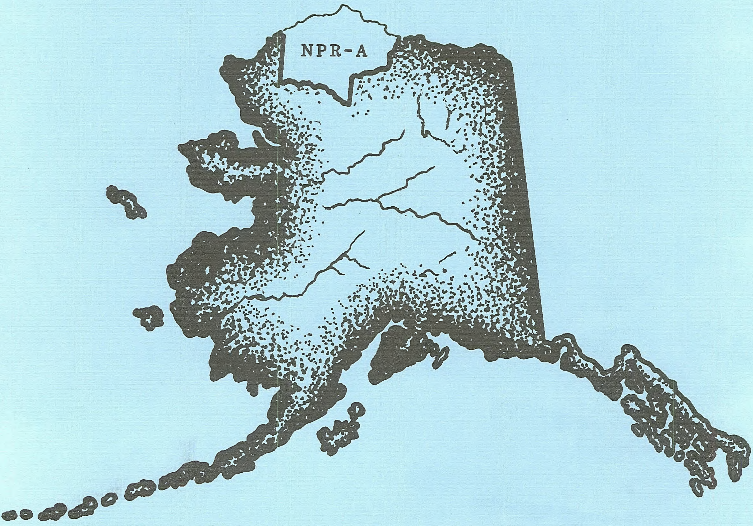
NPR-A